USE OF NODAL TECHNIQUES TO IDENTIFY AND ELIMINATE THE HARMFUL EFFECTS OF PRODUCTION CHOKES ON ESP WELLS

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ABSTRACT

Electrical submersible pumping is perhaps the most inflexible of any artificial lift methods because any given ESP pump can only be used in a specific, quite restricted range of pumping rates. If used outside its recommended liquid rate range, the hydraulic efficiency of the pump rapidly deteriorates; efficiencies can go down to almost zero for pumping rates lying well outside of the lower or upper limits. In addition to the loss of energy and the consequent decrease in profitability the ESP system, when operated under such conditions, soon develops mechanical problems that can lead to a complete system failure. An improper installation design or inaccurate information on the well's inflow capability always results in a mismatch between the design rate and the actual pumping rate. The usual result of these troubles is a workover job and the running of a newly-designed ESP system of the proper lifting capacity.

Since the capacity of the ESP system, without using an expensive VSD (variable speed drive) unit, cannot be easily changed, wellhead chokes are often used to restrict the pumping rate and to force the ESP pump to operate within the recommended liquid rate range. This solution, of course, is very detrimental to the economy of the production system because the pressure drop across the choke causes high hydraulic losses and a considerable waste of energy.

The paper investigates the negative effects of surface production chokes on the energy efficiency of ESP systems using NODAL analysis tools. The proper way of conducting a NODAL analysis for this purpose is detailed along with the description of power flow in the ESP system. The calculation of energy losses in system components is detailed and the relative importance of the individual losses is shown. The elimination of the problems associated with the use of surface chokes is investigated and the proper parameters of the necessary VSD unit are found.

INTRODUCTION

The objective of artificial lift design is to set up a lift system having a liquid producing capacity matching the inflow rate from the oil well at hand. Since the mechanical design of the lifting equipment is only possible in the knowledge of the probable liquid rate, one has to have a very precise estimate on the production rate attainable from the given well. Design inaccuracies or improperly assumed well rates can very easily result in a mismatch of the design and actually produced liquid volumes. The main cause of discrepancies between the designed and produced well rates, assuming proper design procedures are followed, is the improper estimation of possible well rates, i.e. inaccurate data on well inflow performance. The consequences of under-, or over-design of lifting systems can lead to the following:

- If the artificial lift equipment has a greater capacity than the well then its efficiency cannot reach the designed levels; mechanical damage may also occur.
- In case the well's productivity is greater than the capacity of the lifting system, one loses the profit of the oil not produced.

Over-, and under-design of artificial lift installations happens in the industry very often and professionals know how to deal with them. Some lifting methods, like gas lifting or sucker rod pumping, are relatively easy to handle since their lifting capacity can be adjusted in quite broad ranges after installation. ESP installations, however, do not tolerate design inaccuracies because any given ESP pump can only be used in a specific, quite restricted range of pumping rates. If used outside its recommended liquid rate range, the hydraulic efficiency of the pump rapidly deteriorates; efficiencies can go down to almost zero. In addition to the loss of energy and the consequent decrease in profitability the ESP system, when operated under such conditions, soon develops mechanical problems that can lead to a complete system failure. The usual outcome is a workover job and the necessity of running a newly-designed ESP system of the proper lifting capacity.

One common solution for over-designed ESP systems is the use of a production choke at the wellhead. Installation of the choke, due to the high pressure drop that develops through it, limits the well's liquid rate so the ESP pump operates in its recommended pumping rate range. This solution eliminates the need for running a new ESP system of the proper capacity into the well so it saves the costs of pulling and running operations. At the same time, however, the system's power efficiency decreases considerably due to the high hydraulic losses occurring across the surface choke.

The paper investigates the detrimental effects of surface chokes on the power efficiency of ESP systems and discusses alternative solutions. The analysis is provided for wells producing negligible amounts of free gas and is based on NODAL analysis of the ESP system.

CONDITIONS NECESSITATING CHOKING AT THE WELLHEAD

In the majority of cases ESP installations are designed to operate using electricity at a fixed frequency, usually 60Hz or 50Hz. This implies that the ESP pump runs at a constant speed that depends on the electric frequency and develops different heads for different pumping rates as predicted by its published performance curve. Since installation design is based on the selection of the centrifugal pump, the head vs. pumping rate curve of the pump is a very important design parameter. When designing for a constant production rate, a pump type with the desired rate inside of its recommended capacity range is selected. The number of the required pump stages is found from detailed calculations of the required total dynamic head (*TDH*), i.e. the head required to lift the well fluids to the surface at the desired pumping rate. Thus the head vs. capacity performance curve of the selected pump containing the necessary number of stages can easily be plotted based on the performance of one stage.

For an ideal design when all the necessary parameters of the well and the reservoir are perfectly known the pump will produce exactly the design liquid rate since it will work against the design *TDH*. In this case the head required to overcome all pressure losses necessary to move well fluids to the separator is exactly covered by the head available from the pump at the given pumping rate. This perfect situation, however, is far from being universal; very often inaccuracies or lack of information on well inflow performance cause design errors and the well produces a rate different from the initial goal.

The problem with the conventional design detailed above is that the ESP installation is investigated for a single design rate only and no information is available for cases when well parameters are in doubt. All these problems are easily solved if systems (NODAL) analysis principles are used to describe the operation of the production system consisting of the well, the tubing, the ESP unit, and the surface equipment. NODAL analysis allows the calculation of the necessary pump heads for different possible pumping rates and the determination of the liquid rate occurring in the total system, This will be the rate where the required head to produce well fluids to the separator is equal to the head developed by the ESP pump run in the well.

Fig. 1 shows a schematic comparison of the conventional design with that provided by NODAL analysis. Conventional design calculates the *TDH* at the design rate only and selects the type of the ESP pump and the necessary number of stages accordingly. After selecting the rest of the equipment the ESP unit is run in the well and it is only hoped that actual conditions were properly simulated resulting in the well output being equal to the design liquid rate. If well inflow performance data were uncertain or partly/completely missing during the design phase then the ESP system's stabilized liquid rate is different from the design target. NODAL calculations, however, can predict the required head values for different liquid rates, as shown in **Fig. 1** by the curve in dashed line. The well's actual production rate will be where the required and the available (provided by the pump) heads are equal.

A typical situation happens when the final liquid rate is higher than the target rate, indicating inaccuracies in the well performance data assumed during the design. Since the well's required production is usually dictated by reservoir engineering considerations production of a higher rate is not allowed. The cause of the problem, as shown in **Fig. 1**, is that the actual head requirement (actual *TDH*) is much less than the calculated design *TDH*. The only solution to the problem, if pulling the ESP equipment and replacing it with a properly designed one is not desired, to place a production choke of the proper diameter at the wellhead to limit the liquid rate. The pressure drop across the choke, indicated by the head drop in **Fig. 1**, must be sufficient to supplement the system's actual *TDH* to reach the

TDH used for the original design. This way the head requirement of the production system is artificially increased and the ESP pump will produce the desired liquid rate.

APPLICATION OF NODAL ANALYSIS TO ESP INSTALLATIONS

Basics of NODAL Analysis

Systems analysis (NODAL) principles can readily be applied to the analysis of wells produced by ESP pumps. The production system of an ESP installation is shown with the node points in **Fig. 2**. System components, connected by the nodes indicated in the figure, are (a) the formation, (b) the well section between the perforations and the ESP pump, (c) the ESP pump, (d) the tubing string, (e) the flowline, (f) the surface separator, (g) the liquid column above the pump, (h) the gas column in the annulus. All these components work together when the well produces a stabilized liquid rate to the surface. Determination of this rate is one of the basic applications of NODAL Analysis; the basic steps of the required calculations are as follows:

1. First a Solution Node is selected. This can be any node point in the system the proper selection of which facilitates the evaluation of different assumed conditions.
2. A range of liquid flow rates is selected for subsequent calculations.
3. Starting from the two endpoints of the system (Node 1 and Node 6 in **Fig. 2**) and working towards the Solution Node, the flowing pressures at every node point are calculated for the first assumed liquid rate.
4. After repeating the calculations in Step 3 for each and every assumed liquid flow rate, two sets of pressure - rate values will be available at the Solution Node. These values represent the performance curves for the two subsystems created by the Solution Node.
5. According to a basic rule of Systems Analysis the inflowing and the outflowing pressures at any node must be equal; thus the intersection of the two performance curves defines the well's liquid flow rate under the given conditions.

For the case investigated in this paper, the Solution Node is selected at the ESP pump's discharge (Node 4 in **Fig. 2)** and the coordinate system head vs. rate is used for the analysis. In this coordinate system the given ESP pump's performance curve represents the head available from the pump at various liquid rates. The performance curve of the rest of the production system, representing the head required to produce the given amount of liquid, however, must be calculated and plotted as given in the following. Intersection of the two performance curves will determine the stabilized liquid flow rate developing in the entire production system.

Determination of the liquid rate developing in the ESP system

In order to apply systems (NODAL) analysis to the ESP installation, the variation of flowing pressures in the well should be analyzed first. **Fig. 3** depicts the pressures along the well depth (a) in the tubing string, and (b) in the casing-tubing annulus. The well is assumed to produce a stabilized incompressible liquid flow rate at a flowing bottomhole pressure of *FBHP*, found from the well's IPR (Inflow Performance Relationship) curve. From the depth of the perforations up to the setting depth of the ESP pump, pressure in the casing changes according to the flowing pressure gradient of the well fluid which is approximated by the static liquid gradient. This assumption is acceptable when medium flow rates are produced through big casing sizes; otherwise a pressure traverse including all pressure losses should be calculated. The calculated casing pressure at the pump setting depth is the pump intake pressure (*PIP*).

Starting from the other endpoint of the system, the surface separator, the wellhead pressure *WHP* is found by adding the flowing pressure losses in the flowline to the separator pressure p_{sep}. The pressure distribution in the tubing string starts at the wellhead pressure and changes linearly with tubing length. Flowing tubing pressure has two components: (1) one comes from the hydrostatic liquid gradient, and (2) the other is caused by frictional pressure losses. At the depth of the pump discharge (which is practically at the same depth as the intake) the difference between the flowing tubing pressure and the pump intake pressure (*PIP*) has to be covered by the pressure increase developed by the ESP pump, denoted as Δp_{pump}.

Based on the previous discussions the pressure available at the ESP pump's discharge, as calculated from the well bottom upwards, is found from:

$$p_d = FBHP - (L_{perf} - L_{set})\, grad_l + \Delta p_{pump} \qquad 1$$

where: $FBHP$ = flowing bottomhole pressure, psi,
$grad_l$ = liquid gradient, psi/ft,
Δp_{pump} = pressure increase developed by the pump, psi,
L_{set} = pump setting depth, ft,
L_{perf} = depth of perforations, ft.

The performance curve of the tubing string represents the required discharge pressure of the ESP pump; it is calculated from the separator pressure and the pressure losses in the flowline plus the tubing string:

$$p_d^* = p_{sep} + \Delta p_{fl} + L_{set}\ grad_l + \Delta p_{fr} \qquad 2$$

where: p_{sep} = surface separator pressure, psi,
Δp_{fl} = frictional pressure drop in the flowline, ft,
Δp_{fr} = frictional pressure drop in the tubing string, psi.

Since the available and the required pressures must be equal at the Solution Node, the simultaneous solution of the two formulas for the pressure increase to be developed by the ESP pump results in the following expression:

$$\Delta p_{pump} = p_{sep} + \Delta p_{fl} + L_{perf}\ grad_l + \Delta p_{fr} - FBHP \qquad 3$$

Since the ESP industry uses head instead of pressure, the previous equation is divided by the liquid gradient to arrive at the necessary head of the pump:

$$\Delta H_{pump} = L_{perf} + \Delta H_{fl} + \Delta H_{fr} - \frac{2.31}{\gamma_l}(FBHP - p_{sep}) \qquad 4$$

where: ΔH_{fl} = frictional head drop in the flowline, ft,
ΔH_{fr} = frictional head drop in the tubing string, ft,
γ_l = specific gravity of the produced liquid, **-**.

The previous formula, if evaluated over an appropriate range of liquid flow rates, represents the variation of the necessary head that the pump must develop to produce the different liquid rates from the given well. The head available from the ESP pump is, of course, described by its head vs. rate performance curve valid at a given frequency. The liquid rate developing in the total production system of the ESP installation is found at the intersection of the two curves, where the required and the available heads are equal.

ANALYIS OF CHOKED ESP INSTALLATIONS

The effect of chokes on system performance

The calculation model detailed previously allows one to find the liquid rate developing in the ESP system and at the same time demonstrates the detrimental effects of production chokes on system performance. As shown in **Fig. 1**, the actual head necessary to produce the design rate can be found from NODAL calculations. This head, in case sufficiently accurate data on well inflow performance are used, represents the sum of all pressure losses in the well – ESP unit system and provides accurate information on the ESP system's deliverability. The difference between the *TDH* value used during the original design and the calculated head gives the head drop that occurs across the choke. This head drop causes a significant energy loss in the ESP system, the wasted energy in HP units can be calculated as given here:

$$BHP_{wasted} = 7.368\,10^{-6}\ Q\ \Delta H_{choke}\ \gamma_l \qquad 5$$

where: Q = pumping rate, bpd,
ΔH_{choke} = head loss across surface choke, ft,
γ_l = specific gravity of the produced liquid, **-**.

In cases when the size of the production choke is relatively small with a large pressure drop across it, significant amounts of energy are wasted at the wellhead. The ESP system's energy efficiency and profitability may heavily deteriorate as an effect of this condition. In extreme cases, only running a new, redesigned ESP unit in the well may solve the situation but at an increased cost. The other possibility is the use of a variable speed drive (VSD) unit to change the driving frequency of the ESP motor; this entails the decrease of pump speed and a consequent lowering of the head developed by the pump.

Changing the ESP pump's speed with help of a VSD unit changes the variation of all performance curves with the pumping rate. Based on manufacturer's published performance curves at a given electric frequency (usually 60Hz or 50Hz) any of the performance parameters (head, efficiency, power requirement) can be found at any other frequency by using the Affinity Laws. [1] Use of these laws can lead to several preliminary conclusions for the case studied in this paper when the original ESP unit is used at a reduced speed to decrease the pump's head:

1. The head developed, the power required, and the efficiency of the same pump stage at the lower speed will decrease, as compared to the original design,
2. The loading of the motor and its efficiency will decrease,
3. Due to the reduced current requirement electrical losses in the cable will be less.

The combined effect of these factors will surely cause changes in the total power requirement and in the power distribution of the ESP system. The following example problem is presented to illustrate the changes to be expected.

Example problem

A 6,000 ft well (see **Table 1**) was designed to produce 4,800 blpd using a 97-stage S5000N pump at 60 Hz operation driven by a 200 HP electric motor. After installing the equipment in the well it turned out that the well produced more than its allowable as seen in **Fig. 4**. NODAL analysis using accurate well inflow data allowed the calculation of the required head values, using **Eq. 4**, for the possible range of production rates; as indicated by the dashed line. As seen, the system's stabilized rate, represented by point **1**, is at the intersection of the pump's head performance curve and the required head curve. Since this rate is too high, a production choke at the wellhead is used to supplement the system's head requirement and to shift its operation to point **2** at the desired rate of 4,800 blpd. As seen from the pump performance curves at different driving frequencies, use of a VSD unit at a frequency of 51 Hz eliminates the use of the production choke. In the following, the use of the VSD unit is compared to the original design at 60 Hz operation.

The head drop across the choke is found as 1,843 ft (as read between points **2** and **3**) that causes, according to **Eq. 5**, an energy waste of 65.2 HP. The pressure drop across the choke increases the wellhead pressure to 941 psi from the normal value of 143 psi, found from the separator pressure plus the pressure drop in the flowline. The ESP system's main parameters are listed in **Table 2**, where a comparison of pump and motor performance data between the two cases is given. As seen, the VSD unit decreases motor voltage to 1,849 V where motor power decreases to 170 HP.

When the power conditions are compared, the useful power of fluid lifting is identical and is calculated as 42.5 HP from the formula proposed by **Lea et al.** [2]. The hydraulic and electrical losses in the different components of the ESP installation are calculated from accepted formulae [3] and are listed in **Table 3**. As seen, the biggest difference is in the amount of energy used to overcome the surface backpressure: the choked case requires 57.3 kW as compared to 8.7 kW for the 51 Hz operation. Energy losses in the pump and the motor, in spite of the lower individual efficiencies valid for 51 Hz operation (see **Table 2**), have decreased because of the lower amount of power required to drive the pump against the lower total head. Finally, the ESP system's surface power requirement has decreased from 184 kW to 112 kW for the case with VSD operation. The almost 40% lower energy requirement clearly demonstrates the advantage of a VSD unit over the surface choke for controlling the production rate of ESP installations.

Fig. 5 compares the power distribution in the two cases and shows the relative magnitude of power losses in system components for each case. Here, again, the huge decrease in backpressure losses is clearly seen for the case without the surface choke. The two system's over-all energy efficiencies, i.e. the fractions of the useful hydraulic powers referred to the total powers, are considerably different: the 51 Hz operation with a 38% system efficiency being superior to the choked case with an efficiency of 23% only.

CONCLUSIONS

The paper used NODAL Analysis principles to investigate the negative effects of wellhead chokes often used to control the liquid production rate of ESP installations. Over-designed installations with negligible amounts of free gas production were studied. Main conclusions are as follows.

1. Accurate design of ESP installations requires NODAL calculations using reliable well inflow performance data.
2. The detrimental effects of wellhead chokes on the system's power efficiency can correctly be evaluated by NODAL methods.
3. A calculation model is proposed to describe the head required to produce well fluids to the separator that can be easily used to find the liquid rate developing in the production system consisting of the formation, the well, the ESP equipment, and the surface system.
4. The use of VSDs (variable speed drives) instead of wellhead chokes provides an energy-efficient solution to installation design inaccuracies.

REFERENCES

1. Takacs, G.: "Electrical Submersible Pumps Manual." Gulf Professional Publishing, An Imprint of Elsevier, 2009.
2. Lea, J. F. – Rowlan, L. – McCoy, J.: "Artificial Lift Power Efficiency." Proc. 46th Annual Southwestern Petroleum Short Course, Lubbock, Texas, 1999 pp52-63.
3. Takacs, G.: "Ways to Obtain Optimum Power Efficiency of Artificial Lift Installations." Paper SPE 126544 presented at the SPE Oil and Gas India Conference and Exhibition held in Mumbai, India, 20–22 January 2010.

Table 1
Main Data of an Example ESP Installation

Depth of Perforations, ft	6,000		Design Rate, blpd	4,800
Pump Setting Depth, ft	3,300		Static Res. Pressure, psi	2,500
Tubing ID, in	2.992		Prod. Index, bpd/psi	8
Flowline ID, in	3		Water Cut, %	100
Flowline Length, ft	1,500		Separator Pressure, psi	100

Table 2
Performance Data at Two Frequencies

	60 Hz Operation	**51 Hz Operation**
Wellhead Pressure	941 psi	143 psi
Total Pump Head	3,977 ft	2,134 ft
Head/per stage	41 ft/stage	22 ft/stage
BHP/stage	2 HP/stage	1.2 HP/stage
Required Pump BHP	194 HP	119 HP
Pump Efficiency	71%	64%
Motor Power	200 HP	170 HP
Motor Voltage	2,175 V	1,849 V
Motor Current	54 Amps	39.6 Amps
Motor Loading	97%	70%
Motor Efficiency	83%	81%

Table 3
Power Conditions at Two Frequencies

	60 Hz Operation	**51 Hz Operation**
Useful Hydr. Power	42.5 kW	42.5 kW
Backpressure Losses	57.2 kW	8.7 kW
Tubing Friction	5.9 kW	5.9 kW
ESP Pump Losses	42.0 kW	31.2 kW
ESP Motor Losses	24.6 kW	16.9 kW
ESP Cable Losses	6.5 kW	3.4 kW
Surface Electr. Losses	5.5 kW	3.4 kW
Total Surface Power	**184.2 kW**	**112 kW**

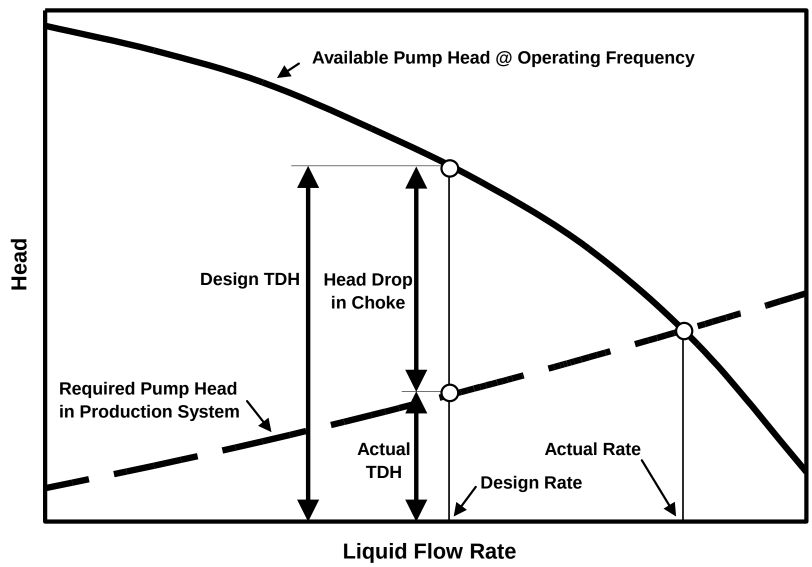

Figure 1 - Schematic explanation for the need of a wellhead choke in an ESP installation.

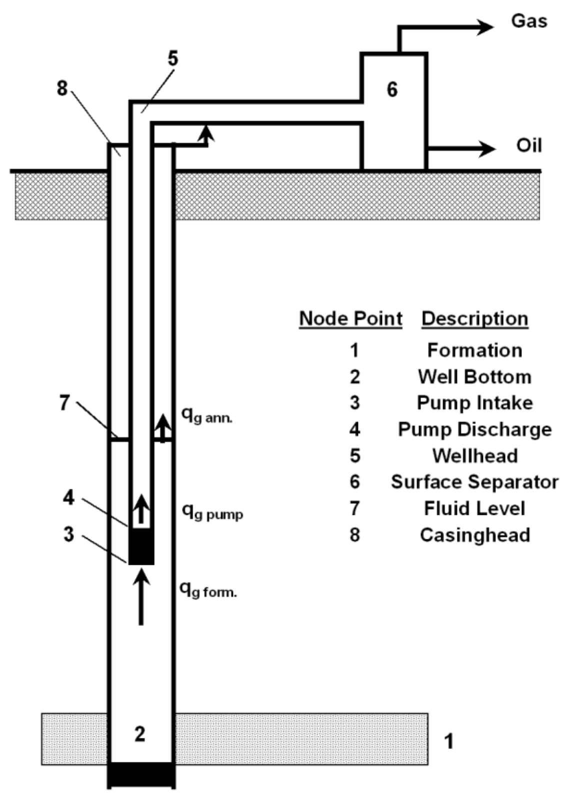

Figure 2 - The production system of an oil well produced by an ESP pump.

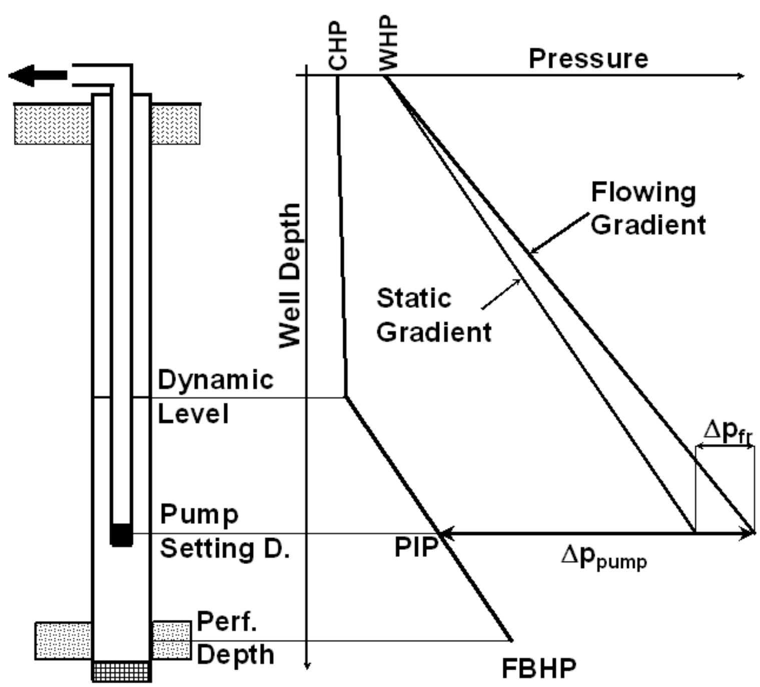

Figure 3 - Pressure distributions in an ESP installation.

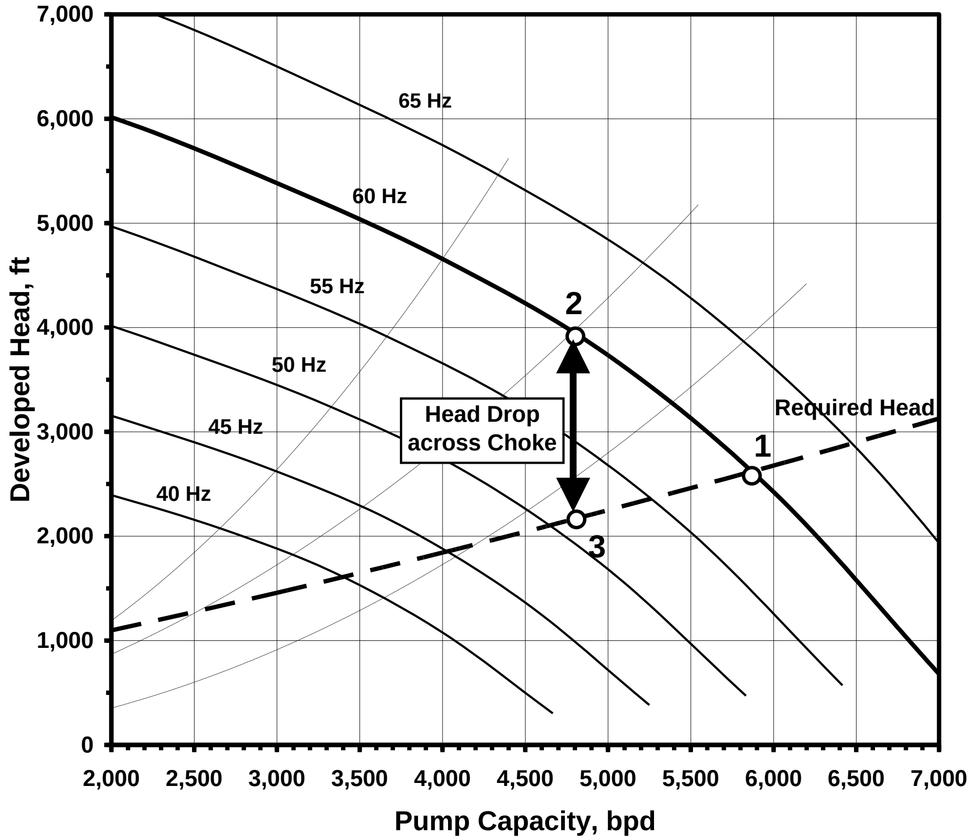

Figure 4 - Example problem of a choked ESP installation.

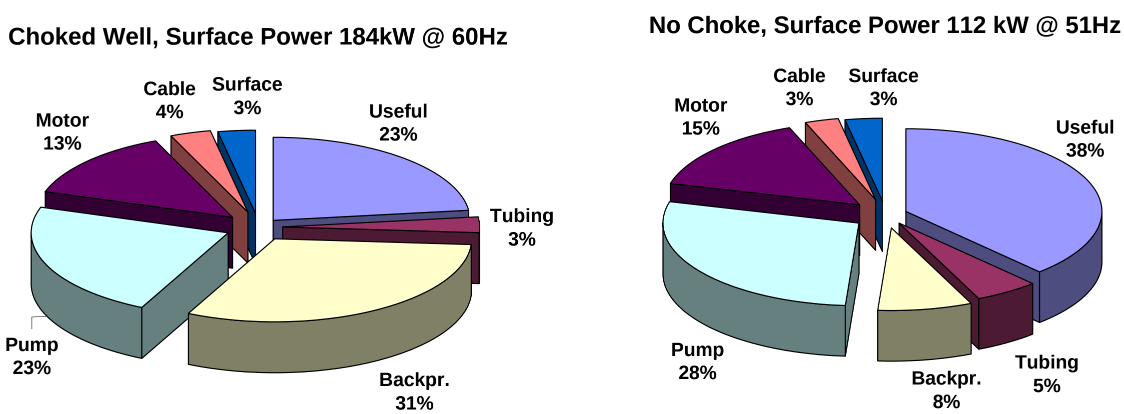

Figure 5 - Comparison of power distribution in the two ESP systems.